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Interesting op-ed re electricity deregulation. The court case referred to is *Colorado Office of Consumer Counsel v. FERC*, Case No. 04-1238 (DC Circuit). The court heard oral argument on 3/14/2007

Opinion > op/ed

Is deregulation of electricity illegal?

BY MARJORIE KELLY AND RICHARD ROSEN

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When economic orthodoxy trumps the public good and violates due process along the way, we're in deep trouble. That is precisely what has happened with the nation's misguided experiment in electricity deregulation, which led to the furor in Maryland and other states over electricity prices spiraling out of control, leaving consumers struggling to pay bills 50 percent to 100 percent higher than in recent years.

If we trace the long road of electricity deregulation to its source, we find the main culprit is the Federal Energy Regulatory Commission (FERC). For nearly two decades, this little-known executive agency has been stealthily undermining the consumer-friendly electricity regulatory framework built during the New Deal.

The problem dates to the era of President George H. W. Bush in the late 1980s, when FERC first allowed a utility company to charge market prices for wholesale power. Avoiding the sunlight of public rule-making, FERC over the years relied upon case-by-case decisions as it gradually shifted much regulatory authority from the settled practice of cost-of-service regulation toward a new market-based framework.

In the process, state utility commissions lost power. The executive branch of the federal government gained power. The public lost out. And the whole process was illegal, according to the attorneys general of Rhode Island, New Mexico, Colorado and Utah, who this month argued their path-breaking case before a federal appeals court in Washington.

Enraptured with market fundamentalism - spread by Enron Corp. lobbying - more than a dozen states, including Maryland, took further steps toward deregulated electricity in the 1990s. This massive experiment is now more than a decade old, and the results can be summed up in a word: disaster. As a recent Tellus Institute study shows, consumers in deregulated states in 2006 paid 55 percent more for electric power than those in regulated states - leaving some residents to choose between staying warm and paying for medicine and food. Further increases have yet to show up in many states, including Maryland, Connecticut and Delaware, where price caps and phase-ins have delayed the problem. Some states now are struggling to undo the mess of deregulation.

"The last time we relied on the market to set electricity prices, it was the Great Depression," and the chaos that followed led to the Federal Power Act of 1935, says Lynn Hargis, a former FERC staffer who is now an energy attorney with Public Citizen.

It is at our peril that we forget the lessons of the Depression: that certain kinds of markets, left to their own devices, can create havoc. Yet what is at work here is not just misguided ideology. In the case heard this month by the federal appeals court for the D.C. Circuit, the four states - represented by Ms. Hargis - argued that in its switch to market-based pricing, FERC violated the Federal Power Act, which requires the agency to see that electricity prices are "just and reasonable."

In short, FERC has been acting illegally. Operating out of a near-religious faith in markets, the commission stripped authority from state utility commissions, which for decades had successfully overseen electricity rates. FERC instead handed electricity price-setting over to markets. And it did so in a way that subverted congressional authority and due process. With their case, the four states aim to return wholesale electricity rate-setting to a cost-of-service basis, thereby restoring vital consumer protections.

This issue relates to a broader stealth attack on the New Deal. And it is part of a larger attempt to have markets take over critical public services such as water, prisons, education and electricity.

The slow-motion disaster of electricity deregulation - and FERC's illegal actions permitting it - can serve as a vital wake-up call. We must remember that public services such as electricity are not commodities but public goods, necessities of life essential to the well-being of all, and thus must be subject to public oversight - not left to markets.

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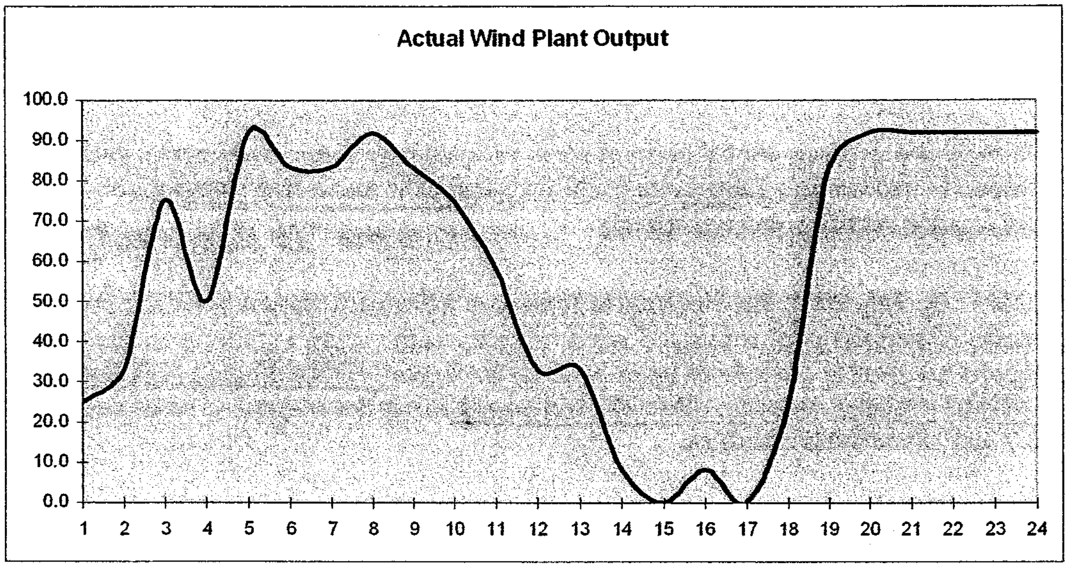
BPA (1)

Figure 4: Illustrative diurnal output of a wind plant



Wind integration in the within-hour time frame

Wind increases the demand for additional regulating (several second response time) and load following (several minute response time) reserves in the within-hour time frame. Control areas carry regulating reserves to manage the minute-to-minute changes in their load and resource balance. Northwest control areas also carry load following reserves to maintain system balance across the remainder of the scheduling period (60 minutes in the Northwest). Regulation and load following reserves are types of operating reserves. Other types of operating reserve include contingency reserves for responding to sudden unplanned generation or transmission[10] outages.

Figure 5 illustrates the combined within-hour behavior of 208 MW of installed capacity from four wind projects in the BPA system. The figure depicts the probability distribution of wind output changes, as megawatts up or down, over the 1-minute, 10-minute and 60-minute time horizons. As can be seen, for all three series, the variability is clustered around zero with low probabilities of occurrence in the tails of the distributions.

[10] Under current rules, wind projects are treated like hydro resources from the perspective of contingency reserves.

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deploying additional sources of flexibility. This is evidenced in other regions of the country such as Colorado and Texas that depend primarily on gas turbines to provide wind integration services. As a result, based on the initial results in Table 4 and the fact that only six of the 16 Northwest control areas are represented in the results, there do not appear to be any fundamental technical barriers to integrating 6,000 MW of wind in the Northwest. It's a question of at what cost.

Cost estimates

Table 5 presents the preliminary cost estimates expressed in $/MWh of wind generation by increasing amount of wind penetration (nameplate wind/peak load).

Table 5: Preliminary wind integration costs from initial utility studies ($/MWh of wind generation)[13]

Utility	Peak Load (MW)	5%	10%	20%	30%
Avista	2,200	$2.75	$6.99	$6.65	$8.84
Idaho Power	3,100		$9.75	$11.72	$16.16
Puget Sound Energy	4,650	$3.73	$4.06		
PacifiCorp	9,400	$1.86	$3.19	$5.94	

Utility	Peak Load (MW)	5%	10%	20%	30%
BPA (Within-Hour Impacts Only)	9,090	$1.90	$2.40	$3.70	$4.60

NorthWestern Energy has reported to the Montana Public Service Commission a wind integration cost of $6.75/MWh for the Judith Gap project for 2006. This value is yet to include the expenses for the operation of the Basin Creek gas-fired plant that are solely attributable to wind integration. The wind integration costs for Basin Creek have not been finalized for 2006. The NorthWestern control area has a wind penetration of 8.7 percent and is currently purchasing all of its control area services at market-based rates.

Key findings

Based on Northwest studies and others from around the world, the cost of wind integration is largely dependent on: (1) the size of the control area where such services are procured in relation to the amount of wind being integrated; (2) the geographic diversity[14] of wind sites and resultant generation patterns; (3) the amount of flexibility available to the power system, and (4) access to robust markets for control area services and storage and shaping products.

Table 5 illustrates a general trend of lower wind integration costs with increasing control area size. The Avista numbers also shine light on the benefits of geographical diversification. By virtue of purchasing a more geographically diverse portfolio of wind projects under its 20

[13] BPA evaluated the current amount of wind in its system (733 MW) and then evaluated costs at 1000 MW (11 percent penetration), 2000 MW (22 percent) and 3000 MW (33 percent). For ease of comparison, the percentage figures have been rounded down slightly in Tables 5 and 6.

[14] Diversity in this context refers to the extent to which changes in wind output at one wind site are different from the changes at other wind sites.

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percent penetration case relative to its 10 percent case, Avista is able to double the amount of wind in its system while simultaneously lowering its per-megawatt hour costs.

Wind integration costs are also driven by dynamic market variables and the amount of system flexibility available to each utility. For hydro-dependent utilities that provide flexibility from their own resources, wind integration costs are largely a function of the spread between peak and off-peak power prices, and current water supply conditions. For control areas with insufficient flexibility to manage their own wind resources, wind integration costs are a function of the market price for control area services and other required shaping products. Absent access to other sources of flexibility, utilities will need to invest in new generating or demand-side resources to secure the needed flexibility.

read NWE + Gas fired Electric

Several of the studies also found that integration costs were very sensitive to the absolute level of wholesale energy market prices. Where market prices rise or fall by 50 percent from today's levels, integration costs would also be expected to change by a similar percentage. **Table 6** expresses the individual utility wind integration costs as a percent of the wholesale price of electricity embedded in each of the studies.

Table 6: Preliminary wind integration costs from initial utility studies expressed as a percent of wholesale electricity market prices

Utility	Peak Load (MW)	5%	10%	20%	30%
Avista	2,200	5.0%	12.7%	12.1%	16.1%
Idaho Power	3,100		15.5%	18.7%	25.8%
Puget Sound Energy	4,650	6.2%	6.8%		
PacifiCorp	9,400	3.1%	5.3%	9.9%	

Utility	Peak Load (MW)	5%	10%	20%	30%
BPA (Within-Hour Impacts Only)	9,090	3.2%	4.0%	6.2%	7.7%

Using Table 6, it is possible to estimate wind integration costs at various levels of wind penetration and market prices and to normalize the wind integration cost estimates of individual studies that may have been based on different electricity market prices.

The Northwest wind integration supply curve

Conceptually, regional wind integration costs can be represented as a supply curve relating cost to the level of installed wind capacity. The incremental costs start out very low, as the amount of variability introduced by a small amount of wind is virtually lost in the larger fluctuations of loads. As the amount of wind increases, the effects of wind variability ultimately dominate, and flexibility needs to be added to the system in direct proportion to the growing wind penetration. Some analysts suggest that there is an upper limit on how high wind integration costs can go based on the cost of gas-fired resources. Consider a combination of a wind project and a gas turbine, each with the same nameplate capacity. The two projects are operated to meet a fixed contractual amount equal to their individual nameplate capacity -- the wind project serving to offset the gas resource when the wind blows. For example, a 300 MW wind farm could

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utilities will share Area Control Error (ACE), which may reduce the amount of regulating reserves each of the individual utilities must carry. Though the incremental demand for regulating reserves from wind energy is quite small, if successful, ADI may take a small bite out of the costs of wind integration as well.

The participating utilities have demonstrated an admirable spirit of cooperation and dedication to solving the technical issues associated with ACE Diversity Interchange. To create greater awareness of this initiative, in July 2007, the participants in the ACE Diversity Interchange pilot should provide a progress report to the Steering Committee of the Northwest Wind Integration Forum.

ACTION 12: By July 2007, the participants in the ACE Diversity Interchange pilot should provide a progress report to the Steering Committee of the Northwest Wind Integration Forum.

Expanded markets for flexibility services

Lessons learned from the ACE Diversity initiative may help expand the availability of other control area balancing services that can effectively pool system flexibility beyond the minute-to-minute time horizon of regulation. This is an important objective. As discussed in Section I, the variability of wind (and control area operations in general) is larger across the 10-minute to 60-minute time horizon than it is across the regulation time horizon. Wind variability in this timeframe is responsible for a majority of wind integration costs and therefore represents the greatest area for potential cost savings.

Services designed to provide additional flexibility across the within-hour time horizon include Supplemental Automatic Generation Control (AGC) and Dynamic Scheduling. These products and their variants allow one utility to take on a portion of the within-hour balancing requirements for another utility's control area.

Through the provision of Supplemental AGC, one entity (control area operator or independent power producer) sells a contractually defined amount of generation flexibility (either unidirectional or bi-directional) to assist a control area in managing its within-hour system variability. Dynamic Scheduling effectively moves the output of a load or generating resource from one control area to another. Other products, such as storage and shaping services, can help manage hour-to-hour wind variability.

The market for control area services and storage and shaping products is very limited. NorthWestern Energy knows this from direct experience. In an effort to purchase additional control area services to manage the 135 MW Judith Gap wind project, NorthWestern has run several solicitation processes and found a very small number of sellers. In 2005, BPA placed a moratorium on the sale of its wind integration services, and Grant County PUD is not offering storage and shaping services to new customers.

The Technical Work Group explored the root causes of the limited activity in the market for flexibility services, and identified several important barriers:

1) There are no formal markets or standard product descriptions for wind integration services;

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Glossary

ACE, Area Control Error: A measure (in MW) of the moment-to-moment load resource balance within a control area. Technically, ACE measures the instantaneous difference in scheduled and actual system frequency and a Control Area's scheduled and actual interchanges with other control areas.

ADI, ACE Diversity Interchange: Coordination among multiple control areas to relax the control needed to balance load, interchange, and generation compared with isolated operations. Relaxed control can be achieved because of the sign diversity (some are net positive or over-generating relative to load and some are net negative or under-generating relative to load) among area control errors of the participating control areas.

AGC, Automatic Generation Control: Generation equipment that automatically responds to changes in system frequency in order to maintain target system frequency (60 cycles per second in the US) and/or the established interchange with other control areas within predetermined limits.

ATC, Available Transmission capacity: The amount of marketable transmission capacity on a defined transmission path after accounting for existing contractual obligations and operating margins.

Busbar: The point at which power from a generating resource is first delivered to the high voltage grid. Busbar costs are calculated before considering the costs of transmitting power to load.

Capacity Factor: A measure of the actual annual energy output of a generating resource divided by the theoretical maximum output, if the machine were running at its rated capacity during all 8760 hours of a year.

Capacity Value: A measure of the amount of additional peak load that can be served by a generating resource without a degradation in system reliability. For example, a 100 MW wind project with a demonstrated 15 percent capacity value could reliably serve an additional 15 MW of peak load.

Control Area: An electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other control areas and contributing to frequency regulation of the Interconnection. (Also referred to as "Balancing Area" or Balancing Authority").

CPS, Control Performance Standard: A metric used by the North American Electric Reliability Council (NERC) to evaluate the performance of control areas. CPS2 requires that 95 percent of imbalances between generation and load above a certain threshold be rectified within 10 minutes.

Dynamic Performance: The extent to which a generating resource or other element can help support grid stability during periods of system disturbance such as a voltage drop.

Flow Gate: A point in the transmission system defined as a grouping of one or more transmission lines, used to measure power flow, usually defined when there is limited capacity across a portion of the transmission system.

LGIA, Large Generator Interconnection Agreement: The Federal Energy Regulatory Commission's standardized interconnection agreement for generating resources greater than 20 MW that proscribes a

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process for review of interconnection requests and a standard contract format. Created by FERC Order 2003A.

Load Following: The deployment of flexible generating resources (or demand-side options) to adjust to changes in loads across the 10-60 minute and longer time horizon. Load following is not technically a type of operating reserve, but as a within-hour service, it is provided between system basepoint adjustments and therefore requires capacity to be reserved from the marketplace given the block-hourly markets in place in the Northwest.

OATT, Open Access Transmission Tariff: The Federal Energy Regulatory Commission Tariff defining the requirements for the provision of non-discriminatory wholesale electrical transmission service.

Operating Reserves: As defined by WECC, the sum of Regulation reserves and Contingency reserves, both spinning and non-spinning, As used in this report, operating reserves include the generation capacity needed to follow moment-to-moment changes in loads and wind (regulation) and longer-term (10-60 minute) changes in loads and wind (load following). As used in this report, operating reserves do not include capacity used to shape the output of wind projects over diurnal or seasonal periods.

OTC, Operating Transmission Capacity: The total transmission capacity of a line or group of lines (flow gate) after setting aside a margin for reliability and non-contract flows.

POS, Plan of Service: An engineering and economic assessment of the physical infrastructure required to interconnect a new resource to the grid or to increase the transfer capacity across a portion of the transmission system.

RAS, Remedial Action Schemes: Protective systems that ensure that corrective actions take place immediately following the forced outage of a transmission line or transmission system element.

Renewable trunk line transmission: A radial transmission line primarily intended to serve multiple renewable resource projects located within a common resource area.

Storage and shaping: The practice of converting the variable hourly output of a resource like wind energy into predictable volumes of power for later delivery, sometimes shaped into flat blocks of peak and off-peak energy.

System flexibility: The ability of both supply-side and demand-side resources to respond to changes and uncertainties in system conditions. Flexibility also refers to the ability of the hydro system to store water for delivery in future time periods.

Regulation: The deployment of fast, responsive generating capacity to manage moment-to-moment changes in the load resource balance of a control area. Regulation is usually provided by units on Automatic Generation Control (AGC).

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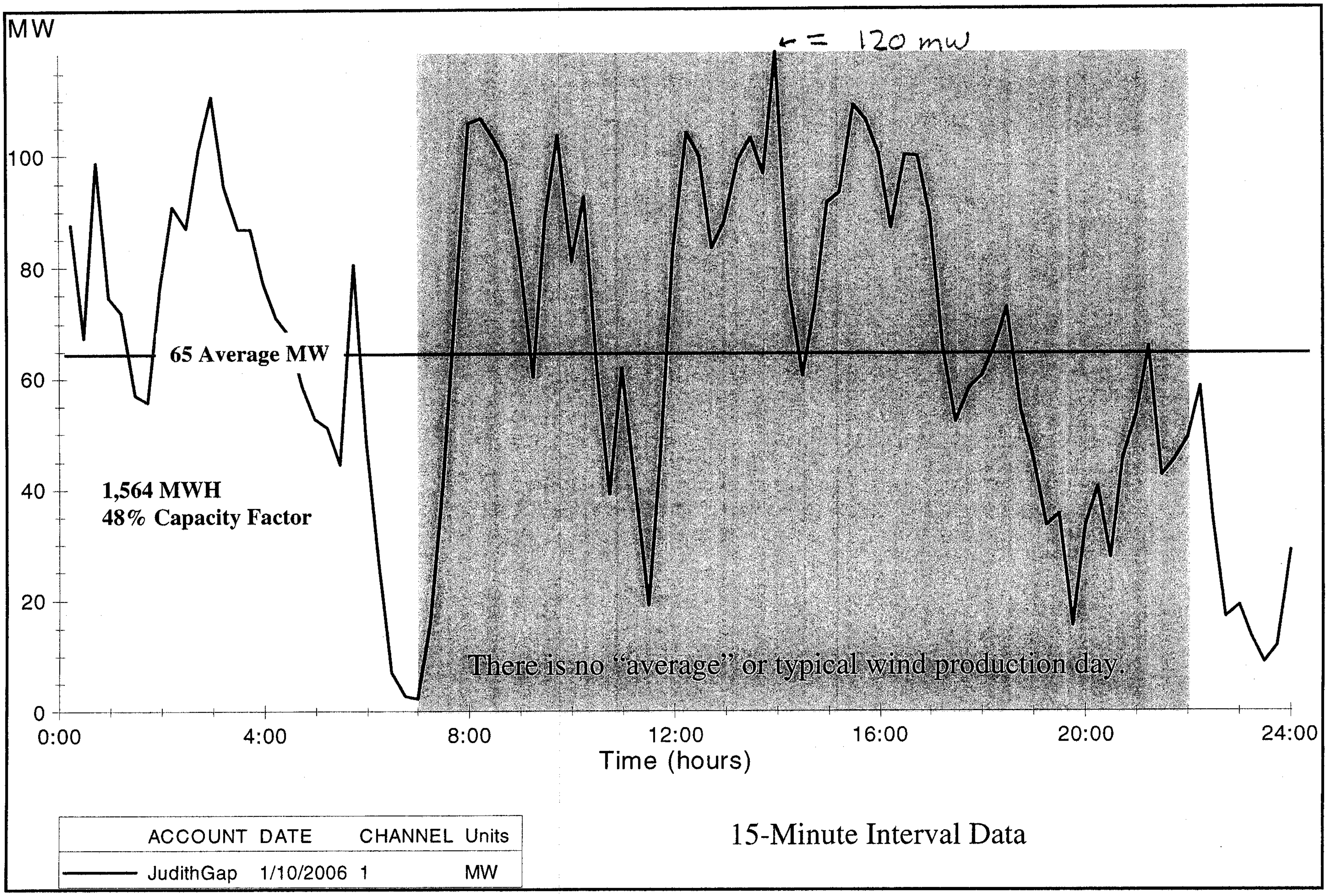

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What have we done?

NWE <u>Default Supply</u> purchased Regulating Reserves and made them available to the Transmission Operator/Control Area Operator

- Historical Transmission Customer Resource (before wind integration)
  - Idaho Power – 60 MW (± 30 MW)
  - Base price $2.7 million / year

Wind Integration

- New Regulating Resource from Avista Corp
  - Purchased at the beginning of 2006
  - 15 MW (± 7.5 MW): ~11% of default supply wind resource
  - Base price: $1.1 million / year:
- Second Purchase from Avista
  - Added in June to correct CPS2 performance
  - 10 MW (± 5 MW)
  - Base price: $740,000 / year
- Regulating reserves to support the new wind generation
  - 25 MW ~18% of default supply wind resource
  - Nearly $1.8 million/year
- Costs are increasing for this product…